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A Potential Evaluation and Pilot Test of CO_2 Miscible Injection in Daqing, China

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Abstract

The paper introduces the entire process for a CO_2 injection in the Fang-48 Group, Daqing Oilfield. A study using experiment and full-field reservoir modeling investigated and optimized the design of a CO_2 miscible flooding project for Fang-48 Group, Daqing. The study began with extensive data gathering in the field and building a full-field three-dimensional geologic model. A full-field simulation model with relatively coarse gridding was subsequently built and used to history match the depletion and waterflood. The focus of the history match is to highlight the remaining oil area. And another target is to form a favorable system for CO_2 injection. A fine-griCO_2 model is set up after the history match. Both pure CO_2 and WAG injection are simulated. In the continuous CO_2 injection, different injection rates are simulated. In the CO_2 WAG injection simulation, different water-gas ratios were investigated. The efficiencies of mobility control of all cases are analyzed.

Keywords: miscibility, simulation, slimtube, water-alternating-gas

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INTRODUCTION

According to industrial experience, CO_2 injection is an effective EOR method for variable conventional reservoir [1]. The injection of CO_2 can be divided into miscible and immiscible, which depends on the properties of the reservoir fluids at reservoir conditions and reservoir characteristics. When the reservoir pressure is lower than the MMP, the injectant and crude oil cannot reach miscibility [2, 3]. Conversely, miscible floods happen at the pressure higher than the MMP. Experience shows that miscible displacements obtained better ultimate recoveries than immiscible displacement did [4–6]. Over last two decades, CO_2 miscible flood has been widely used, especially in the United States [1, 7]. The first CO_2 pilot in 1976, the Western Texas fields in the Permian basin conducted the first CO_2 miscible flood. Since then, more and more CO_2 miscible projects are carried out. According to the result of all the successful injections, the CO_2 miscible injections could yield an extra of 5 ~ 15% of OOIP in incremental recovery [8].

GEOLOGICAL OVERVIEW

Daqing oil field was discovered in a continental fluvial-delta sedimentary environment and features complex geologic conditions and high permeability contrasts. The Songfangtun is one of the most typical fields in the Daqing [9]. Most pilot experiments are carried out in this region. The target reservoir of the flood involved seven layers of the P I: P $I3_3$, P $I3_2$, P $I2_2$, P $I2_1^2$, P $I2_1^1$, P $I1_2$, and P $I1_1$. The sediments of the P $I3_3$ and P $I3_2$ were mainly characterized by the high sinuous distributary channels. Several of those channels laterally merge into compound meandering belt which has a significant thickness. Some abandoned channels with different directions and sizes remaining at both the edge of meandering belt and inside suggested that the channels were seriously meandered. The fluvial sandstone is the priority in the P $I3_3$ and P $I3_2$ units with high permeability. The P $I2_2$ and P $I2_1^2$ are characterized by low sinuous and relative straight distributary channel. Because of the decay of the hydrodynamic nearby the flatten bank, the channels on delta distributary plain frequently branched off or merged so that an anastomozed pattern was formed [9]. The widths of single sandbodies showed strong diversity, while compound meandering belt had rarely been seen. And facieses among channel sandstones, interchannel sandstones, and pinch-out zone sandstones showed significant differentiation. Sandstone horizontal distribution presented pretty complicated. Compared with P I3 units, the proportion of channel sandstone declined in the P $I2_2$ and P $I2_1^2$, so did the high permeability layers. The P $I2_1^1$, P $I1_2$ and P $I1_1$ were characterized by straight underwater distributary channels, and the banded or anastomozed sedimentary framework which was overall formed by narrow band or discontinuous channel sandbody, front thin sandstone and off-sheet reservoirs [10].

The interest in this simulation was initially spurred by the fact that the water cut kept increasing and the oil production rate kept decreasing in the past several years. The oil production rate in this field began to decline since 1999. And the water cut rose significantly due to the water injection. To slow down the oil production decline, an investigation of enhanced oil recovery becomes necessary.

SLIMTUBE MMP MEASUREMENT

A multipoint slimtube test was conducted to measure the MMP. The recovery of oil after 1.2 PV of injection gas plotted versus pressure provides a measure of miscibility, together with the shape of the recovery curve which should have an elbow at a point above 90% oil recovery to indicate the attainment of miscibility. The slimtube itself is a means of forcing the flow to be one-dimensional. So far, there is neither a standard design, nor a standard set of criteria for obtaining MMPs with a slimtube [11–13]. Early gas breakthrough with a low slimtube recovery at 1.2 PV injected is normally associated with an immiscible displacement, like the points 1 ~ 3 shown in Figure 5. Displacement behavior that is usually associated with channeling or bypassing in a porous medium can also apply in a slimtube. The diameter design is typically related to the viscous fingering. Viscous fingers in the tube are suppressed by transverse dispersion if the tube is small enough in diameter and the displacement rate is low. The internal diameter used in this measurement is 0.46 cm. By making the slimtube long, the relative length of any viscous fingering region is kept small in comparison to the scale of the tube length. Smaller diameter tubing is also justified to reduce the impact of lateral viscous fingering. There is no sharp distinction between miscible and immiscible gas flow as far as mass transfer effects are concerned. Component exchange between the phases still takes place at pressures below the MMP [6, 14]. Porosity has been discussed as a screening parameter for a slimtube, because poor slimtube performance has been associated with higher porosity slimtubes in the past. However, porosity is only a qualitative indicator; and no correlation exists to establish a maximum porosity limit for an acceptable slimtube experiment. In the measurement of Fang oil/CO_2 MMP, five pressure points were measured in total. The result indicates the MMP in Fang-48 is 23.2 MPa.

SIMULATION INVESTIGATION

Fundamental Modeling

The research mainly covered the history match, analysis of the current injection and production system, and the estimation of different EOR methods. The simulation model was based on the properties of the Fang-48 field. A 50 by 60 grid model consisting of three layers was defined to describe the reservoir. Totally, 30 wells were involved in the simulation.

History Match

The depletion stage was from 1976 to 1979. Seven production wells were drilled during this stage. The main mechanism has been shown to be solution gas drive, in conjunction with fluid expansion and gravity drainage. By analyzing the geological data and the development history, the edge water drive also played an important role, especially in slowing the pressure drop. The invading aquifer, which intruded into the southwest corner of the reservoir, resulted in an imbalance of the reservoir pressure, thus, an imbalance of the production and water cut. At the end of this stage, the average individual water cut in the northeastern zone was less than 5%, while the southwestern part was roughly 65%. The water flood began in 1979. Three injectors started injecting in this year. The oil production rate was increased by 60%. During the water flood, the imbalance of pressure and a low sweep volume factor also existed. The recovery factor was 36.13% at the end of the history match of the primary and secondary phases. According to the outcomes of the simulations, only some of the producers responded to the injected water. Others were still dominated by the solution gas drive. Some un-swept areas were left, especially the north part of the reservoir, which has not been swept well by the water flood. There were two factors which formed the rich zone of the remaining oil in the central reservoir: (1) The unevenness of production and injection and (2) The heterogeneous nature of the reservoir. There is also a blind side on the boundary of the reservoir where it is difficult to form a circulation of the reservoir fluids in a closed region.

Development Adjustment

A robust network pattern is fundamental to a successful water flood. As analyzed above, the existing well pattern was imperfect. To improve the sweep efficiency and to raise the recovery, a pattern adjustment was necessary. Based on the outcomes of the history match, three new injectors were assigned to the rich remaining oil zone. Meanwhile, to minimize the imbalance of the reservoir pressure, three producers were converted to injectors. The new pattern has six injectors and seven producers (some producers were shut in during the water flood).

Result: By contrasting the oil saturation with different well patterns, the adjustment has improved the flood efficiency significantly. The un-swept areas were mobilized gradually. The number of responding producers increased.

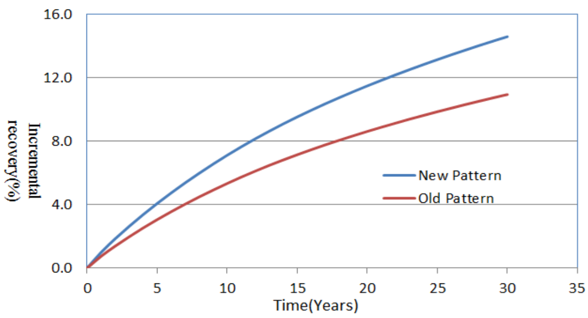

Fig. 1: Incremental Recoveries for Different Networks.

As shown in Figure 1, the incremental recovery of the new well pattern is much higher than that of the old one. When the water cut reaches 97%, the adjusted pattern has an incremental recovery of 4.1%.

Field Scale Simulation

Building of the field scale CO_2 model integrated results from the previous water-flood and MMP test to design a model that would provide high confidence results. The full-field CO_2 model proved to be useful for project design and optimization. Each individual case could be evaluated for CO_2 flood potential. Total field production and gas plant operations could also be modeled. Twenty-year prediction was run for all cases. In all CO_2 injection cases, the injection scheme was fixed with six injection wells and seven production wells.

Continuous CO_2 Miscible Injection

Under the injectivity limits of the reservoir and above the minimum miscibility pressure, three injection rates were tested to determine the impact of injection rates on development efficiency in the previous research. The recovery results of those three rates show no significant difference. The continuous CO_2 injection is reinvestigated in the refined model and the basic injection rate is used for the reference case of the following WAG analysis.

Recovery Factor and Override Observation

Because of the existence of vertical permeability and gravity difference, the override can be significant. In this case, the injected gas went preferentially through the upper layer due to the gravity of CO_2 being lower than the crude oil. Correspondingly, there was more gas to mobilize the crude oil in the top layer; the sweep efficiency and displacement efficiency in the top zone was shown to be much better than the lower zone. Comparing three injection rates, the prediction results showed the highest injection rate had the lowest override effect. In other words, controlling injection rate would reduce the effect of the override, in a sense.

Oil recovery versus injection PV is shown in Figure 2. Increasing the injection rate by 20% (rate 2), or by 40% (rate 3), the change of injection rate impacted the recovery factor only slightly; however, it speeded up the oil recovery rate dramatically, as seen in Figure 3. Meanwhile, the peak oil production rate increased respectively, but the timing of the peak oil production rate did not change. Since the contribution to the oil recovery factor was not significant by increasing injection, CO_2 usage efficiencies for different injection rates were almost the same.

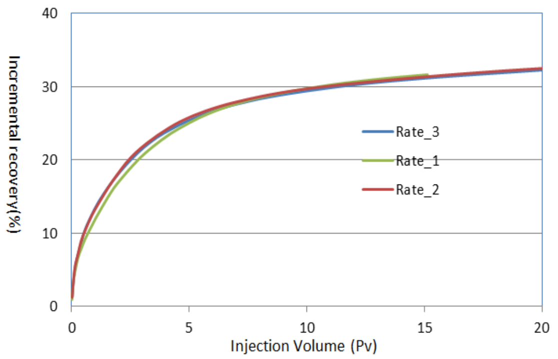

Fig. 2: *Incremental Recoveries from CO_2 Flood for Different Injection Rates.*

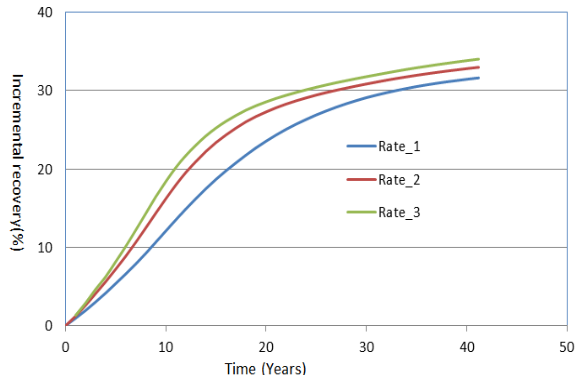

Fig. 3: *Incremental Oil Recovery from CO_2 Flood.*

Application Concerns

As discussed above, the continuous injection can contribute a significant incremental recovery. But the override made the vertical recoveries different. The development efficiency in the lower zone was reduced due to the flood disadvantage which was caused by the gravity difference and vertical permeability. The fingering became weak with the injection continuing, the sweep efficiency showed significant improvement but the displacement efficiencies in the relatively-low-perm zones were still low.

All CO_2 floods displayed a low displacement efficiency basically because the viscosity of the injectant was much lower than that of the crude oil. The mobility was unfavorable for the flood. For CO_2 flooding, the vertical sweep efficiency was relatively low due to the density difference between the injectant and crude oil. Although the dispersion of the injected CO_2 had the contact between the displacing phase and displaced phase volumetrically increased, the unfavorable mobility ratio resulted in the relatively low displacement efficiency.

Water Alternating CO_2 Miscible Flood (WAG)

Based on the significant CO_2 flooding potential shown above, a further research was conducted. In order to minimize the above two adversities, a water alternating CO_2 injection (WAG) process was designed. To evaluate the performance of miscible CO_2 flooding, extensive computations were conducted. WAG ratio and slug size were principally investigated. The slug sizes covered 0.1 HCPV, 0.3 HCPV, and 0.5 HCPV. WAG ratios involved 2:1, 1:1, and 1:2. So, there were nine cases in total. A hysteresis model was employed in the WAG simulation.

Flooding Efficiency

According to the analysis of WAG prediction, the flooding efficiency is getting better with the increase of the CO_2 proportion. Taking 0.3 HCPV CO_2 injection as an example, when the WAG ratio is 2:1, the incremental recovery factor is 5.4%. Decreasing the WAG ratio to 1:2, the incremental recovery factor goes up to 9.46%. Figures 4 and 5 show the water cut and incremental recovery change for 0.3 HCPV CO_2 injection. All predictions of three slug sizes show that the recovery efficiency depends on the CO_2 injection volume in the Fang-48 field. Although WAG as the solution of heterogeneity and gravity segregation improved the sweep efficiency, there is no contribution to the ultimate recovery. Analyzing the oil saturation maps, the WAG injection has a better sweep efficiency compared with CMI. But the residual oil saturation is relatively high. The flooding efficiency presented by ultimate recovery is lower in WAG process.

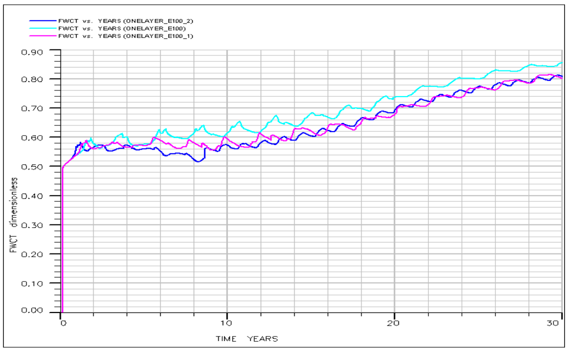

Fig. 4: *Water Cut Tendencies of WAG Injections for 0.3 HCPV.*

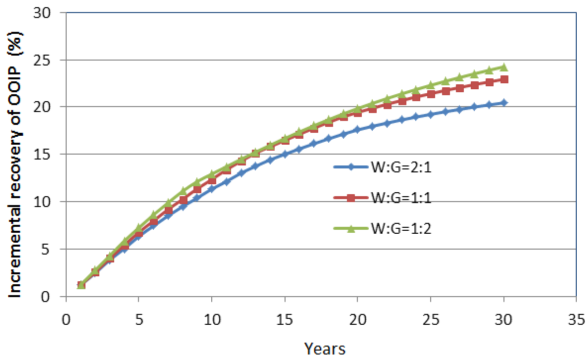

Fig. 5: *Incremental Recovery of OOIP for 0.3 HCPV CO_2 Injection.*

CONCLUSIONS

Detailed modeling of the remaining oil after water flooding improved the understanding of the enhanced oil recovery potential. The MMP tests showed that it is easy to obtain miscibility with Fang-48 oil at reservoir conditions. Full-field simulation of CO_2 injection offered valuable reference in the estimation of feasibility and efficiency of CO_2 EOR in Fang-48. The simulation results of field scale continuous injections indicate that the miscible flood has a significant potential in Fang-48 reservoir. Relevant to the thickness and heterogeneity of Fang-48 reservoir, the continuous injection results in a slight override and viscous fingering in the simulation model due to the density and viscosity weaknesses of CO_2. The WAG injection improved the above problems. The comparison of ultimate recoveries indicated that although the sweep efficiency is improved with WAG injection, the flooding efficiency of continuous injection is still better than that of WAG.

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